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"An Economic Perspective of the New
Forward Capacity Market Concept"

Jonathan A. Lesser, Ph.D.
Bates White LLC

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Introduction

My name is Jonathan Lesser. I am a Partner with Bates White, LLC, a national consulting firm offering services in economics, finance, and business analytics to leading law firms, FORTUNE 500 companies, and government agencies. I am an economist by training and trade, and I have spent over 20 years in the energy industry, working for electric utilities, government regulators, trade associations, and as a consultant. After all that time, I can say without hesitation that I understand electric markets less than when I started. While that no doubt reflects fewer functioning brain cells on my part, it may also reflect the continued transformation of electric markets, with all of the uncertainty and upheaval that transformation continues to create.

I have been asked to provide an economic perspective of the new market concept to a forward capacity market (FCM) from the existing locational installed capacity market (LICAP). Before I begin, however, an important disclaimer:

While my remarks today aren't being sponsored by any market participants, I previously testified on behalf of Duke Energy North America (DENA) in the *Devon Power* case that dealt with capacity market issues. I will do my best to provide an unvarnished take on the economic issues surrounding the new market design as a disinterested (but not uninterested) economist. Nevertheless, my remarks today cannot help but be affected by the research I performed as part of that proceeding on behalf of DENA.

Economic Issues

I want to address several economic issues today. First, I will discuss why I concluded that a separate capacity market is needed. Second, I will review the locational capacity market structure ISO-NE developed initially, and how it was transformed into a forward capacity market (FCM) mechanism under a Settlement Agreement. Third, I will discuss the transition mechanism that has been developed, and the economic issues that mechanism raises. Fourth, I will discuss the economic issues surrounding the proposed FCM mechanism, the specific market rules for which have yet to be written. Finally, I will discuss other potential issues, such as the economic and policy implications should FCM prices be higher than expected, if the underlying generation supply market is deemed not competitive, and so-called "seams" issues between New England and NY/PJM.

Why a separate capacity market?

"Reliability," which in my non-engineering way I define as the ability to meet the demand for electricity over time – whether during the next second, ten minutes or the next ten years – is what economists call a *public good*. What that means is first, reliability for one is reliability for all, something economists call *non-exclusivity* and *non-rivalry* in consumption. Second, it means that the operating decisions made for an individual generating unit may create *spillovers*, that is, effects on others, both good and bad. Third, as with all public goods, left to their own individual energy suppliers won't provide enough system reliability, because they can't reap the full economic benefits of doing so, and would rather "free ride" on other suppliers' investments. This is a typical characteristic of public goods: non-exclusivity means that someone who doesn't pay can still consume the public good just as much as someone who does. As a result, no one has an incentive to invest. After all, why invest when you can "free ride?"

How have these public good characteristics manifested themselves in New England? ISO-NE establishes reliability targets and operating standards. Reliability targets establish levels of installed capacity deemed necessary to ensure there is enough surplus capacity available to meet consumers' electric demand at any time. ISO-NE also maintains operating standards to ensure that generators do not operate in ways that compromise the safety and integrity of the transmission system. And, ISO-NE ensures that all load serving entities (LSEs) obtain their "fair share" of ancillary services. Finally, ISO-NE classifies some transmission system investments as "Pool Transmission Facilities," or "PTF," which provide benefits to the entire region. Thus, a new transmission line around Boston may be defined as a PTF investment and, as such, the cost to build it will be shared by everyone in New England. Since the majority of growth in New England is occurring in the southern portion, it's no surprise that this "share and share alike" policy has been challenged by some northern states that are not experiencing much load growth. This is also an issue for the transition capacity market mechanism that has been adopted.

Opponents of installed capacity markets have adopted two conflicting positions. Some opponents argue that there is no need for separate capacity markets, because a well-functioning, uncapped energy market will provide all the capacity that's needed. Others argue that separate capacity markets only provide "windfalls" to generators, and have no impact on energy markets. Taken together, these arguments represent a classic “free rider” response: capacity market opponents want to “rely on” others’ generation investments to provide system reliability, and not have to pay for it themselves. But, in the tradition of public goods, such behavior will ultimately result in a system that is unreliable and harmful to customers.

I should note that MISO is taking an energy-only market approach. How well this approach works remains to be seen. The obvious advantage is that it is simpler. The disadvantage will be apparent if an energy-only market fails to attract intermediate and peaking resources for which energy revenues alone will not provide sufficient returns.

Addressing the Challenges of Developing a Capacity Market

One of the challenges in developing a capacity market, in addition to the general problem of too little investment in a public good, is market intervention by regulators and politicians. When price spikes make headlines, it is too tempting politically not to intervene, or threaten to intervene, so as to protect defenseless customers from “selfish generators” who “take advantage of an energy crisis.” One has only to look at the political reaction to high gasoline prices in the wake of Hurricane Katrina, and again this past summer, to see that the supply of political demagoguery is abundant.[1] This is not to discount the risk of anticompetitive behavior and the need to monitor suppliers’ behavior. But price caps are blunt instruments that have numerous spillover effects of their own. Moreover, high prices do not in themselves mean there is anti-competitive behavior.

Another problem for new capacity investment is price volatility. Ironically, price volatility is exacerbated, by differentiating markets. Although these focused

[1] As Groucho Marx famously quipped, “Politics is the art of looking for trouble, finding it everywhere, diagnosing it incorrectly, and applying the wrong remedy.”

markets can send more appropriate price signals to investors, they can result in a higher concentration of suppliers, increased potential for market power and greater price volatility. As a result, individual investment decisions, as well as individual operational decisions, will have more profound impacts on wholesale energy prices in these localized markets. In essence, this is a "lumpy" investment problem. Generation developers will want to build large plants that can exploit economies of scale, but those large plants can drive prices significantly lower, making it impossible for them to recoup the cost of their investment or, at the very least, reducing returns. As a result, a developer might be more inclined to avoid siting in a constrained area, even though that's precisely where the power is most needed.

The solution to this dilemma is the creation of a separate capacity market, with well-defined requirements to ensure reliability. As initially envisioned, this capacity market would replace the existing system of "reliability must run" (RMR) contracts, which are cost-based regulatory mechanisms. Eliminating, or at least minimizing reliance on those non-market contracts was one of FERC's original goals in the *Devon Power* proceeding.

ISO-NE's Original Design

In *Devon Power*, ISO-NE originally began with a downward sloping demand curve for installed capacity, similar to what had been put into effect in New York. The goal was to avoid the "feast-or-famine" capacity market prices that had been experienced in the past with a fixed installed capacity requirement (ICR). In that market, capacity prices had essentially been zero, because there was an overall surplus of generating capacity in New England, except of course in Southern New England where it was needed. Moving to a downward sloping demand curve and supplier bids, it was thought, would result in a competitive market for capacity.

After FERC requested some additional justification for some of the specific parameters ISO-NE chose, however, ISO-NE refiled its proposal with a more elegant, but more complex, market design. Not only were many market participants confused about this design, the complexity of that design required a number of changes as the proceeding went on. Moreover, some LSEs and consumer advocates believed that: (a) the resulting capacity prices would provide windfalls to generators; (b) they would not contribute to improved system reliability; and (c) the approach would result in too much reliability. And, yes, those three arguments are contradictory.

None of this, by the way, is meant to cast aspersions on ISO-NE. They were trying to solve a complex problem in a way that had been mandated by FERC. Unfortunately, at least in this economist's view, as the proceeding wore on complexity and elegance appeared to take precedence over practicality, and the admonition that "perfection is the enemy of the good," came to be.

The ALJ issued a decision accepting some aspects of ISO-NE's approach and rejecting others. Then, the case went into settlement negotiations, and an entirely new approach, dealing with creation of "forward" markets for capacity ("FCM"), emerged that, ironically, had been brought up in the original proceeding, but was determined to be outside the scope of the case. The mechanics of that mechanism were described earlier today, so I won't go through those. Instead, I will focus on some broader aspects, including the transition mechanism that will begin in December and last 3 ½ years, until the full FCM takes effect in June 2010.

The Transition Mechanism

During the transition period, payments for installed capacity will be set at negotiated levels. Under the Settlement Agreement ("SA"), the rates will be $3.05/kW-month for the remainder of the 2007 power year (December 2006 – May 2007, as well as the 2008 power year (July 2007 – May 2008). Rates will then increase to $3.75/kW-month during June 2008 – May 2009 and $4.10/kW-month for the period June 2009 – May 2010.

The first real test of the new market design will be in early 2008, when the first forward capacity auction (FCA) is expected to take place. Subsequent annual auctions are designed to "refine" the capacity market prior to the start of each power year (June – May). The results of those auctions, which I will discuss later, are likely to have significant consequences as to whether a competitive capacity market will emerge, or whether ISO-NE will continue to require non-market solutions to ensure system reliability.

The negotiated payments during the Transition Period have two significant characteristics. First, they are roughly half of the $7.50/kW-month estimated cost of new entry (CONE). Moreover, that CONE value was itself highly contested in *Devon Power* because it depends on a number of assumptions, including critical ones about the stability and certainty of the new market design. Second, the negotiated payments will create "winners" and "losers," even though that was one of the most contentious portions of the original Devon Power proceeding. However, unlike under the proposed LICAP market design, during the transition period, the "winners" will be LSEs in capacity-constrained zones, such as here in Southern New England, some of whom opposed ISO-NE's entire idea of a separate capacity market to improve reliability in their areas. The "losers" during the transition period will be LSEs in unconstrained zones, such as Maine, who will subsidize their Southern New England brethren, and some generators, who will continue to need RMR contracts to survive economically.

Oddly, the SA discusses the "savings" to consumers from adopting the SA rather than the previously anticipated LICAP payments under ISO-NE's approach. While the SA notes that the Transition Payment approach will save consumers money (while tacitly admitting that some of the benefits to "savers" are transfers from "payers"), the new FCM approach raises a number of economic questions:

(1) How much will the transition payments really save since, presumably, the capped payments will likely mean continuation, and possible expansion, of cost-based RMR contracts?

(2) If the transition payments serve as a *de facto* 3½ year price cap, will short-term gains to consumers be followed by proportionally larger long-term losses under the FCM, as is the usual outcome with any price-capped market? Will developers commit to investing in sufficient new capacity? What will happen during (and at the end of) the Transition Period if the market-clearing FCM prices are higher than expected? Will New England regulators and politicians allow the new market time to evolve or will they once again succumb to the temptations of short-term demagoguery?

(3) How will existing generators respond to capped transition payments? Will generators seek to export more capacity into the New York market, so as to capture greater value? Will they de-list or retire? Will new generators have embraced the New England market or will the end result ultimately be a system in which RMR contracts remain the backbone of the transmission system?

(4) Will the FCM work if the there is too little capacity investment during the transition period? Will the "Inadequate Supply" and "Insufficient Competition" provisions of the SA work as they are designed to, or will the rules create additional regulatory uncertainty and discourage new investment?

Trying to answer these questions completely would likely involve a months-long regulatory proceeding. Since I only have a few minutes, however, let me briefly discuss these four questions.

1. Will capacity costs paid by consumers actually be lower during the transition?

There are two potential problems with proclaiming savings for consumers. First, a number of RMR contracts are set at rates much higher than the transition payments. Unless new generating or transmission capacity will appear sooner than expected, customers in constrained areas such as Connecticut and NEMA/Boston will continue to pay for a number of existing RMR contracts whose prices are far higher than the transition payments. Moreover, LSEs in unconstrained zones, such as Maine, may end up paying more if the set transition period payments are higher than what they would have paid under the original LICAP proposal, with its downward sloping demand curve. In fact, on September 8, 2006, the Maine Public Utilities Commission filed a Request for Rehearing of the SA because of this issue.[2]

Additionally, one of the ISO's arguments in *Devon* was that a failure to adopt the proposed LICAP structure would result in higher costs for customers because more RMR contracts would be needed without that structure. The LSEs, not surprisingly, disputed that conclusion, with some going so far as to suggest the entire system was too reliable and that the ISO's annual determination of the necessary installed capacity reserve (ICR) was too high. It is true that ISO-NE's reliability standard of a 1-in-10-year loss of load probability (LOLP) is a common planning standard. It is also true that determining the "true" economic value of reliability to consumers is a tremendously difficult exercise, made more so by the public good nature of reliability.

[2] Re: Devon Power, LLC, et al., Docket No. ER03-563-060, Motion to Lodge of the Maine Public Utilities Commission in Support of Request for Rehearing, September 8, 2006.

2. How will the transition period price caps affect the long-term FCM?

Most economists agree that artificial price caps do more harm than good. While they provide benefits in the short-run, they reduce the incentive to develop new supplies. This leads to proportionally larger price increases when the caps expire or eventual rationing. Thus, one can ask whether the transition mechanism will delay development of a truly competitive FCM, and, if so, will consumers end up paying more in the long run?

As has been observed in some of the expiring price caps for default energy service in several states, such as Delaware, Maryland, and New Jersey, lifting multi-year price caps can unleash large price adjustments, which have two effects: First, it is more difficult for consumers to plan for and adjust to rare, but large price changes, than it is for them to adjust to small, but more frequent ones. Second, large price changes that occur as a result of changes in regulation can quickly become politicized, as has been the case in those same three states.

Suppose, for example, that the price of capacity increases from $4.10/kW-month in May 2010 to the top of the initial allowed range, $10.50/kW-month, in June 2010. One has to wonder whether there will be howls of outrage and, most disturbingly, calls to revise or even scuttle the SA. Given the history of electric industry restructuring in New England and the controversy over the creation of a separate capacity market, it would be prudent for any generation developer to factor such risks into decisions to build in New England.

Thus, one of the key unanswered questions at this time is how the transition period will affect the development of a competitive FCM in New England over the long term. But, one of the difficulties with answering this question is that the specific rules governing the FCM will not be filed with FERC until February 2007. Thus, as the saying goes, "the devil is in the details," and those details aren't known yet. As University of Maryland Prof. Peter Crampton, who participated in the settlement negotiations on behalf of ISO-NE, stated in his Affidavit accompanying the SA that was filed:

> The framework laid out in the settlement agreement appears sound. However, great care and attention to the details will be required to assure a successful implementation.

Prof. Crampton is correct, of course. But the essence of a negotiated settlement is compromise, which means it is quite possible that crucial implementation details necessary for the economic underpinnings of the FCM to lead to new capacity investment, a more reliable electric system, and lower costs.

For example, the SA discusses mechanisms to be developed that will allow intermittent resources, such as wind and hydro generation, to participate in the FCM. Since the essence of participating in the FCM is a requirement to be available when called on, it is not clear how this will be accomplished, unless intermittent resources are somehow firmed up with an equivalent amount of nuclear or fossil-fuel generating capacity. Similarly, the SA promises that "a distinct method will be determined to allow energy efficiency and demand response resources (other than Real Time Demand Response) to be fully integrated as Qualified Capacity."[3] The Vermont Public Service Board (Vermont PSB) has already discussed a $4 million estimate for payments to Vermont's state-overseen efficiency utility, called Efficiency Vermont.[4]

As a survivor of the DSM-wars, my experience with estimating realized energy and peak capacity savings from energy efficiency investments is that such calculations are quasi-religious at best, layering uncertainties (such as the market value of capacity) on top of assumptions (such as the demonstrable ability of such efficiency measures to reduce demand at times of system peaks.)

[3] Settlement Agreement,, Section II.E.2.b.

[4] Memorandum dated September 28, 2006, from Susan Hudson, Clerk of the Vermont PSB, to Act 61 participants.

Given dollar estimates like that of the Vermont PSB, however, one can expect vigorous negotiations, whose outcome will be colored not only by economic principles, but also by political calculation.

In a September 25, 2006, presentation, Gordon van Welie, the CEO of ISO-NE, stated that over 4,000 MW of new generating capacity projects in New England has been announced.[5] How much of that will materialize, or where, or what type of generation will actually materialize, remains unclear. Developing new generation has never been easy in New England, especially in relatively populated areas where new capacity is most needed. The risk of further market intervention, therefore, cannot be discounted. That risk increases regulatory uncertainty and will increase costs.

3. How will the transition period and FCM affect existing generators?

Only new capacity providers can actually bid capacity into the market. existing generators' capacity is taken as a given to determine the incremental quantity of new capacity needed. So, if ISO-NE sets the ICR equal to 32,000 ME and existing generators can provide 30,000 MW, the initial demand for new capacity is 2,000MW. However, existing generators can bid "out" of the capacity market, either by submitting de-list or export capacity bids. This can be thought of as "creating" a demand curve for new capacity: as the price in the auction falls, more de-list/export bids will be submitted and the demand for new capacity will increase. So, in the numerical example, if there are a total of 1,000 MW of de-list bids at the CONE price, the demand for new capacity will be 3,000 MW.

From an economic standpoint, existing generators will have a number of strategic decisions to make. During the transition period, existing generators with

[5] Gordon van Welie, Presentation at, *Lights Power Action Solutions for New England's Energy Future*, Boston, September 25, 2006. A copy of his presentation is available at: http://www.iso-ne.com/pubs/pubcomm/pres_spchs/2006/ gordon_van_welie_remarks_092506.pdf.

RMR agreements will continue to be paid under those agreements during the transition period. So, there will be no savings to consumers during the transition period associated with those agreements. Moreover, the SA states RMR agreements will terminate at the start of the first Commitment Period under the FCM, beginning in June 2010, but doesn't restrict the rights of generators to continue their RMRs or for others to challenge them. Presumably, the higher the market-clearing prices in the FCM are, the less likely generators will be to ask for continuation of RMR agreements. On the other hand, opponents of RMRs will be more inclined to challenge them under the same circumstances. Thus, the regulatory dance is likely to persist.

For generators whose RMR payments are greater than the already established first year ceiling price of $10.50/kW-month, they must decide whether to participate in the FCM auction as export capacity or to de-list. Such a decision will be driven by expectations of not only the first year FCA clearing price, but also by clearing prices in subsequent years and the likelihood of remaining under an RMR agreement because of constrained transmission. This is a difficult economic problem to solve.

It's also useful to recall FERC's original goal of eliminating the need for RMR contracts through a market system. Because the transition payments are low, ISO-NE's original predictions in the Devon case that more generators would apply for those contracts will likely be realized. Not only will this reduce realized "savings" to consumers, if any, it will set up a series of strategic economic decisions among generators.

Constrained Areas

To the extent that new transmission investment has not eliminated constrained areas, decisions to de-list generation are more likely to affect the final market-clearing prices in the FCM, simply because a given change in capacity in area with a smaller localized ICR will cause a proportionally greater fluctuation in demand. This increased price volatility is likely to adversely affect development of new capacity resources. Moreover, all de-list bids will be reviewed by the Market Monitor to determine whether,

> "[t]he proposed bid is consistent with the Resource's net risk-adjusted going-forward and opportunity costs, recognizing, among other things, infra-marginal rents, availability adjustments, and PER deductions. … The details of this review shall be developed in the Market Rules."

One can imagine the complexities and potential areas of disagreement associated with these reviews, especially the treatment of future uncertainty about energy and capacity prices, not only in New England, but also in New York, and also with respect to the prices of fuel. Similar issues will apply to generators whose RMR payments are below the ceiling price.

4. How well will the Insufficient Supply and Inadequate Competition provisions work?

In the Devon proceeding, there was much debate about the impacts of market power on LICAP prices. The FCM will be subject to similar concerns, and, as a result, determinations of market power will be important, such as whether specific capacity providers are "pivotal." The SA sets out provisions to address market power, including specific pricing rules that will reduce the prices paid to existing capacity holders to 10 percent above the CONE. New capacity suppliers, even though they could be pivotal, will be paid the clearing price.

This may raise several issues. First, to the extent that the Market Monitor determines there is insufficient competition, it is not clear why paying a new capacity supplier a presumably above-market price makes economic sense. Second, if the price paid to existing generators is reduced to levels below what some generators receive as RMR payments as the follow-up auctions occur, (assuming that the RMR agreement is needed), then what happens? Unfortunately, the rules aren't written yet.

Can the FCM Work?

Much of the specific mechanics of the FCM remain to be worked out. In addition to some of the already mentioned procedures to be developed, such as the Market Monitor determining the "validity" of de-list bids, much uncertainty remains, especially if it is determined that the FCM is either not providing adequate supply or if there is insufficient competition. The complexity and penalties are such that the proposed FCM raises substantial uncertainty for new investment. Worse, it may not lead to new generating capacity in the areas where it is most needed.

Moreover, the history of restructuring in New England indicates a high degree of regulatory and political intervention in the development of new markets. This was the case in the original LICAP proposal, so perhaps I am skeptical to think that this intervention will not end with the FCM. To that extent, regulatory uncertainty may continue to be a critical issue, it will continue to retard new capacity investment, require continued reliance on RMR agreements, and stifle development of a workably competitive market for installed capacity.

A way out

If the concerns I have discussed are legitimate – and supporters of the FCM may believe those concerns are ill-founded – can those concerns be addressed so as to create a workable capacity market? In principle, they can, but only if the affected parties are willing.

The FCM remains too complex, with too many uncertainties and after-the-fact determinations. These will deter investors. The requirement that de-list bids first be certified by the Market Monitor to determine whether those bids are anticompetitive is a prescription for more litigation. Those price caps, coupled with price caps in the energy market, will only increase economic distortions. If there is to be a capacity market, let it be a true market.

Second, to address concerns about the potential for high prices when the FCM takes effect, LSEs can aggressively develop real-time demand-response programs that can reduce their capacity obligations quickly, while giving generators time to build new capacity. A side benefit of an uncapped capacity market will be greater potential for these types of programs.

Third, expand "fast-track" generation siting programs for new capacity development. Under the FCM, generators have three years between bidding and ensuring their plants are running. If developers think they will be stopped by delays and protests, they will not commit. If states, especially states where capacity is most needed, ensure there are sites that are fully permitted and ready for development, including the necessary infrastructure for fuel delivery (e.g., gas pipeline capacity, rail lines, etc.), developers will be more likely to commit to new projects. The sad fact is that, years of "not-in-my-backyard" regulations have contributed to the current generation and capacity "crisis" in Southern New England.

Fourth, the risk of future regulatory and political intervention needs to be reduced. While it is difficult to bind future regulators to past decisions, perhaps an alternate market structure can be reserved as a "default" if all participants in New England – generators and LSIs – determine that the FCM is failing to work as intended. My own recommendation would be a return to the simple LICAP model that ISO-NE began with in *Devon Power*. While not perfect or "elegant," it is straightforward and reasonable, and has worked well in New York.

Dr. Jonathan Lesser has over twenty years of experience working for electric utilities, government regulators, and as an economic consultant. He has testified on major economic and regulatory issues affecting the electric and natural gas industries, including utility structure and operations, cost allocation and rate design, asset valuation, capital investment decision strategies, the cost of capital, depreciation, risk management, incentive regulation, utility mergers, and general regulatory policy. He can be reached at jonathan.lesser@bateswhite.com, (01)202.747.5972.